CHAPTER 9

REVISE TAXATION OF ENERGY AND NATURAL RESOURCES

The tax law has long been used to subsidize the exploration, development and production of natural resources. While subsidies for particular activities generally lead to inefficiencies and misdirect investment capital, the subsidies applied to national resource development have also been important in maintaining a viable domestic energy industry. Accordingly, these subsidies would be modified under the Administration proposals in order to establish greater neutrality in the taxation of various commercial activities, while retaining those incentives believed necessary to maintain exploration and development of domestic mineral resources.

REPEAL ENERGY TAX CREDITS

General Explanation

Chapter 9.01

Current Law

A. Business Energy Tax Incentives

Special tax credits are available for business firms to encourage investments in conservation and renewable energy technologies and to encourage production of alternative fuels. These incentives can be grouped into three major categories:

1. Energy Investment Tax Credits. Solar, wind, geothermal property and ocean thermal property qualify for a 15 percent energy investment tax credit. Certain hydroelectric generating property qualifies for an 11 percent credit. Qualified intercity buses and biomass property are eligible for a ten percent energy credit. These energy credits terminate on December 31, 1985.

A ten percent energy investment tax credit was available for certain other types of energy property but this credit generally expired on December 31, 1982. However, if such energy property qualifies under "affirmative commitment" rules, the credit continues to be available until December 31, 1990. Under these rules, projects requiring two or more years for completion will continue to be eligible if (a) all engineering studies were completed and all necessary permits filed before January 1, 1983, (b) binding contracts for 50 percent of specially designed equipment are entered into before 1986, and (c) the project is completed and placed in service before 1991. In addition, in the case of hydroelectric generating property, the credit is available through December 31, 1988, if an application has been filed with the Federal Energy Regulatory Commission before January 1, 1986.

2. Production Tax Credits. A credit of up to $3 per barrel of oil equivalent is available for certain qualifying fuels. In general, the credit is available for qualifying fuels produced from facilities placed in service after December 31, 1979, and before January 1, 1990, and sold after December 31, 1979, and before January 1, 2001. The credit phases out as the average wellhead price of domestic crude oil rises from $23.50 to $29.50 per barrel. The maximum credit and the phaseout range are adjusted for inflation. Qualifying fuels include (a) oil produced from shale and tar sands, (b) gas produced from geopressured brine, Devonian shale, coal seams, a tight formation, or biomass, (c) synthetic fuels produced from coal, (d) fuel from qualified processed wood, and (e) steam from solid agricultural byproducts.

3. Alcohol Fuels Credit and Excise Tax Exemptions.

a) Alcohol fuels mixtures. Present law provides a six cents per gallon exemption from the nine cents excise tax on gasoline and a similar six cents per gallon exemption from the 15 cents diesel fuel excise tax if the taxable products are blended in a mixture with at least ten percent alcohol ("gasohol"). The term alcohol is defined to include only alcohol derived from a source other than petroleum, natural gas, or coal (including lignite). The provision terminates after December 31, 1992.

b) Alcohol fuels. Present law provides a nine cents per gallon exemption from the excise tax on special motor fuels for a fuel consisting of at least 85 percent alcohol derived from a source other than petroleum or natural gas and a four and one-half cents per gallon exemption if the source is natural gas. The provision terminates after December 31, 1992.

c) Alcohol production credit. A 60 cents per gallon income tax credit is provided for alcohol used in gasohol mixtures with gasoline, diesel fuel, and special motor fuels. A like credit is allowed for alcohol used as a fuel other than in a qualified fuels mixture. A lesser credit of 45 cents per gallon is provided for alcohol of at least 150 proof but less than 190 proof. The term alcohol is defined to include only alcohol derived from a source other than petroleum, natural gas, or coal (including lignite). This credit terminates on December 31, 1992, and may be carried forward for 15 years, but not to a tax year beginning after December 31, 1994. If a production credit is claimed with respect to alcohol, the exemption from the gasoline and special fuels excise taxes is not allowed.

d) Taxicabs refund. A four cents per gallon exemption from the excise tax on gasoline, diesel fuel and special motor fuels is provided if used in certain taxicabs that are rated at above-average fuel economy. The exemption expires on September 30, 1985.

B. Residential Energy Tax Credits

Under current law there are two categories of residential energy tax credits:

1. Conservation credits. A 15 percent credit is available to individuals for the first $2,000 of expenditures for certain energy conservation equipment, such as insulation or storm windows and doors, for a maximum credit of $300.

2. Renewable energy credits. A 40 percent credit is available to individuals for the first $10,000 of expenditures for solar, wind or geothermal energy property, for a maximum credit of $4,000.

To be eligible for the residential energy tax credits, expenditures must be with respect to the taxpayer's principal residence. In the case of the residential conservation credits the

residence must have been in use before April 20, 1978. The credits expire on December 31, 1985. Unused credits may be carried over through 1987.

Reasons for Change

Congress enacted the energy credits because oil and gas price controls understated the replacement cost of energy. Because of price controls, consumers did not have the incentive to invest in energy conservation and alternative fuels. The absence of free-market prices created an economic rationale for energy tax incentives. Since these incentives were enacted, however, crude oil prices have been decontrolled and natural gas prices are being decontrolled. As a result, these tax credits are no longer needed.

Proposal

The energy tax incentives would be allowed to expire or would be terminated on December 31, 1985.

Effective Dates

A. Business Energy Tax Incentives

1. Renewable Energy Investment Tax Credits. All renewable energy investment tax credits would be allowed to terminate on December 31, 1985. Unused credits may be carried forward or backward. However, for hydroelectric generating property the present law affirmative commitment rules will continue to apply.

2. Energy Investment Tax Credits. All conservation and other alternative source energy investment tax credits would terminate on December 31, 1985. However, present law affirmative commitment rules would continue to apply.

3. Production Tax Credits. All production tax credits would terminate on December 31, 1985. However, eligible fuel produced from a well drilled, or from facilities completed, before January 1, 1986, and sold before January 1, 1990, would continue to be eligible for the credit.

4. Alcohol Fuels Credit and Excise Tax Exemptions. The credit for alcohol fuels would be available for eligible alcohol fuels produced from facilities completed before January 1, 1986, and sold before January 1, 1993. All excise tax exemptions would terminate on December 31, 1985. The qualified taxicab refund that is scheduled to terminate on September 30, 1985, would not be renewed.

B. Residential Energy Tax Credits.

The residential energy tax credits would be allowed to expire on December 31, 1985, and would not be renewed. Carryovers of unused credits would continue to be available through 1987 as under current law.

Analysis

The energy tax credits implement questionable energy policies. Subsidies provided for alternative fuels, for example, are significantly in excess of the price that should be paid for replacement of crude oil. With an alcohol fuel production credit at 60 cents per gallon, the Federal government is paying a subsidy of $25.20 (in addition to the price paid by the consumer) in order to save a barrel of oil currently valued at under $30.

The energy tax credits also add to the complexity of our tax laws and impose additional administrative burdens upon the Internal Revenue Service. A taxpayer compliance study with respect to individual income tax returns for taxable year 1979 disclosed that of $473 million of taxpayer claims for energy tax credits, $126 million in claims would have had to be disallowed had the Internal Revenue Service been able to fully audit all returns. Taxpayers failed to claim only $26 million in credits that they were otherwise entitled to claim. Thus, by Internal Revenue Service estimates, more than one-quarter of the amount of energy credits claimed by taxpayers for 1979 should not have been allowed. The high error rate resulted from confusion over dollar limitations, qualification of equipment for credit, as well as improper carryovers. According to another study, in the case of the geothermal credit, nearly 95 percent of claimed credits were invalid because of an apparent massive misunderstanding of the applicable rules.

The residential energy credits, particularly the renewable energy credits, tend to favor middle- and upper/middle-income households, and cannot be justified on the ground that they are necessary to help low-income persons adjust to higher energy prices. For example, in 1982, households with adjusted gross income in excess of $30,000 accounted for about 60 percent of all renewable energy expenditures eligible for tax credits, but accounted for only 51 percent of total adjusted gross income.

Finally, many of the conservation improvements subsidized by the residential energy credits would have been made without the tax credits because of decontrol and the increase in world oil prices in 1979. Thus, in many cases, tax credits have served merely to reduce the tax burden of middle- and upper-income households, rather than to encourage additional energy conservation efforts.

REPEAL PERCENTAGE DEPLETION

General Explanation

Chapter 9.02

Current Law

The design of cost recovery rules for the extractive industries is complicated by the fact that the quantity of reserves and the rate of production vary widely for different deposits. Moreover, production may be prolonged through the application of various enhanced recovery techniques. Thus, unlike ordinary depreciation methods, which may reasonably be applied to generic categories of investment in plant and equipment, the rate of cost recovery for mineral properties is appropriately determined on a property by property basis.

Under current law, recovery of capital investment in mineral properties is generally determined under the cost depletion or the percentage depletion method. Under cost depletion, a deduction is allowed each year equal to the product of the unrecovered costs and the ratio of the quantity of minerals sold during the year to the quantity of minerals estimated to be available as of the beginning of the year. By taking into account a property's cumulative production record, cost depletion permits a more accurate allocation of costs incurred to individual time periods than methods employing a fixed service life or rate of recovery.

Under percentage depletion, a deduction is allowed based on a statutory percentage of the gross income from the property. The percentage of gross income that may be claimed is generally 15 percent for oil, gas and geothermal, and ranges from 5 to 22 percent for other minerals. The allowance is limited to 50 percent of the net income from the property, and certain additional limitations apply in the case of oil and gas. Unlike all other cost recovery systems, a taxpayer may continue to claim percentage depletion after all the expenditures incurred to acquire or develop the property have been recovered.

Taxpayers with an economic interest in a mineral property must claim the greater of percentage depletion or cost depletion. Percentage depletion generally is not allowed in the case of oil and gas production. However, natural gas producers with long-term contracts and certain independent producers and royalty owners (i.e., taxpayers that do not refine or market more than specified quantities of product) are allowed to claim percentage depletion. Independent producers and royalty owners may claim percentage depletion only on production up to 1,000 barrels of crude oil (or, in the case of natural gas, crude oil equivalents) per day. This quantity limitation must be allocated between different properties, and, at the taxpayer's election, between oil and gas production. In the case of coal and

iron ore, corporate taxpayers must reduce such deductions by 15 percent of the amount in excess of the basis of the property. Taxpayers denied percentage depletion, such as integrated oil companies, may only use cost depletion.

The excess of percentage depletion over the adjusted basis of the property is a tax preference item for the corporate minimum tax and the noncorporate alternative minimum tax.

Reasons for Change

Percentage depletion allows deductions to be claimed in excess of a taxpayer's investment, and thus is more accurately viewed as a general production subsidy than as a method of cost recovery. The subsidy provided by percentage depletion, however, does not provide an efficient incentive for resource production. Because of the relatively lengthy interval between the acquisition of a property and initial production (if, in fact, the property is ever productive), percentage depletion encourages development of existing properties rather than exploration for new deposits. Moreover, because the allowance is limited to 50 percent of the property's net income, the subsidy is cut back for developers of marginally profitable properties. Thus, the greatest benefits are provided where a subsidy is least needed, i.e., to the developers of the most prolific or highly concentrated deposits.

Even if percentage depletion allowances were limited to a taxpayer's investment, percentage depletion would not be an appropriate cost recovery method. The rate of cost recovery would depend on the volume of production, and thus would favor owners of deposits that can be produced more rapidly over owners of less productive properties (even if such production might represent a smaller fraction of total reserves). Percentage depletion also provides faster cost recovery when mineral prices rise, and less rapid recovery when prices fall. These factors are unrelated to the appropriate rate of cost recovery.

Although percentage depletion is inappropriate as a general method of cost recovery, its total repeal could have a significant adverse effect on a segment of the domestic oil and gas industry. Recent sharp declines in oil and gas prices have strained the profitability of certain marginal producing properties. These so-called "stripper wells" (i.e., wells producing less than 10 barrels per day) comprise about 15 percent of domestic oil production. A change in existing law to deny percentage depletion could make many stripper wells unprofitable on an after-tax basis and result in their early abandonment. A significant decline in stripper well production could, in turn, increase the country's dependence on foreign energy, exacerbate the problem of the trade deficit, and again make the U.S. vulnerable to concerted political or market action by foreign producers. The clear national security interest in maintaining energy independence supports current retention of percentage depletion for oil and gas stripper well production.

The rationale for retaining percentage depletion with respect to stripper well production does not extend to owners of royalty interests in stripper wells. The treatment of the stripper well royalty owner has no direct bearing on the operator's decision to maintain production, and thus such owners should be subject to the generally applicable cost recovery rule, i.e., cost depletion. Royalty owners would, of course, benefit from royalties earned from continued stripper production as well as from the lower marginal tax rates that would be provided under the Administration proposals.

Proposal

Percentage depletion would generally be repealed for all minerals. Percentage depletion would be phased out over a five year period beginning on January 1, 1986, by reducing the applicable percentage depletion rates by 20 percent each year. In the case of oil and gas stripper wells, however, percentage depletion would continue to be available for independent producers (but not royalty owners). For this purpose, stripper well status is to be determined on a well by well basis.

Taxpayers unable to claim percentage depletion would use cost depletion to recover their adjusted basis in the property, if any, indexed for inflation. To the extent that percentage depletion is available, the excess of percentage depletion over the deduction allowable for cost depletion would be treated as a tax preference item for purposes of the corporate and noncorporate alternative minimum taxes. See Chs. 13.03, 13.04.

Effective Date

The phase out of percentage depletion would be effective for production beginning on or after January 1, 1986.

Analysis

In general, the subsidy provided by percentage depletion is inefficient and should be terminated. Given the decline in mineral prices over recent years, however, immediate termination of percentage depletion could create significant dislocation. A phase-out of percentage depletion over several years should permit producers to continue in production until the industry adjusts.

In addition, percentage depletion has had the effect of maintaining production from many marginal oil and gas wells. In order that domestic energy production not be significantly impaired, percentage depletion for stripper well production by independent producers should be retained.

REVISE MINIMUM TAX ON INTANGIBLE DRILLING COSTS

General Explanation

Chapter 9.03

Current Law

Intangible drilling costs ("IDCs") are those costs of drilling and preparing oil, gas, and geothermal wells that generally are not incurred for the purchase of tangible property. These intangible costs include not only amounts paid for labor, fuel, materials, and technical services necessary for the actual drilling, but also site preparation costs (which may require the construction of man-made islands from which to drill or the digging of canals to move drilling rigs and other equipment) and costs incurred in the transportation and installation of drilling rigs, production casing, and wellhead equipment (but generally not the cost of the rigs, casing, or equipment).

Under current law, taxpayers have the right to elect to expense IDCs as incurred or to capitalize them. They may also elect to expense only the IDCs on unsuccessful wells ("dry holes") and to capitalize the IDCs on productive wells. If capitalized, the costs are recovered through depletion or depreciation. IDCs are subject to recapture upon disposition of the property with respect to which they are deducted. Corporate taxpayers are allowed to expense only 80 percent of their IDCs; the balance must be capitalized and amortized over 36 months.

The amount of "excess" IDCs is an item of tax preference for the alternative minimum tax for noncorporate taxpayers. The "excess" is calculated by subtracting from IDCs paid or incurred (other than costs of dry holes) (1) the IDCs that would have been allowable had such IDCs been capitalized and amortized over 10 years, and (2) the taxpayer's net income from oil, gas, and geothermal properties during the taxable year. IDCs are not subject to the corporate minimum tax (except for personal holding companies).

Reasons for Change

Intangible drilling costs are a major portion of the costs necessary to locate and develop oil and gas reserves. IDCs associated with successful wells contribute to an asset that has productive value over more than a single year; from a tax accounting perspective, conventional matching of income and expense would require that they be recovered over their full productive period. Expensing of IDCs, as permitted under current law, thus departs from ordinary accounting principles and is appropriately viewed as an implicit incentive for domestic energy production.

A change in the treatment of IDCs, however, from the expensing allowed under current law to recovery over their full productive life would dramatically alter the taxation of oil and gas production. Moreover, the change in tax burden would be concentrated on exploratory and developmental activities, leaving the tax treatment of existing producing properties largely unaffected. The downturn in oil prices in recent years has already caused a substantial decline in oil drilling activity. In this climate, a lengthening of the period over which IDCs are recovered could cause a significant further decline and thus reduce domestic oil production. Any such reduction would increase the country's dependence on foreign energy, exacerbate the problem of the trade deficit, and again make the U.S. vulnerable to concerted political or market action by foreign energy producers. The clear national security interest in maintaining energy independence thus supports retaining cost recovery rules for IDCs that provide an incentive for domestic energy production.

At the same time, taxpayers should not be able to eliminate their tax liabilities through excessive use of the option to expense IDCs. Accordingly, it is appropriate that a portion of IDCs be treated as a minimum tax preference item for both corporate and noncorporate taxpayers. The portion of IDCs so treated should reflect the extent to which the present value of the taxpayer's deduction for IDCs exceeds the present value of the deductions for such costs that would be allowed under generally applicable accounting rules. Furthermore, for purposes of the minimum tax, no distinction should be made between taxpayers who are engaged in the oil and gas business and other taxpayers incurring IDCs. Accordingly, the current law rule under which net oil and gas income reduces the amount of IDCs treated as a minimum tax preference item should be repealed.

Proposal

The current law option to expense IDCs would be retained. However, eight percent of the IDCs paid or incurred on successful wells in a taxable year would constitute a tax preference for purposes of the proposed corporate and noncorporate minimum taxes. See Chs. 13.03 and 13.04. The percentage of IDCs included as a preference item would not be reduced by the taxpayer's net oil and gas income.

Effective Date

The inclusion of IDCs in the individual and corporate minimum tax would be effective for costs paid or incurred on or after January 1, 1986.

Analysis

The Administration proposal would reduce the potential for corporate and noncorporate taxpayers engaged in the production of oil and gas to escape income taxation as a result of the election to

expense IDCs. Eight percent of IDCs represents the difference between the present value of expensing and the present value of the deductions that would be allowed if the taxpayer capitalized the IDCs and depreciated them as CCRS class 3 property (the same as tangible drilling costs; see Ch. 7.01). The additional tax liabilities incurred because of this proposal should not significantly affect continued development of the nation's energy resources.

REVISE ROYALTY TAXATION

GENERAL EXPLANATION

Chapter 9.04

Current Law

Royalty income received by the owner of a retained economic interest in coal or iron ore production is eligible for treatment as long-term capital gain under section 1231 of the Internal Revenue Code. In order to receive capital gain treatment, the taxpayer must have been an owner of an interest in the coal or iron ore in place for at least six months, and must dispose of the ore under a contract by which he retains an economic interest therein. Under such contract, the taxpayer treats the difference between amounts received and the adjusted cost depletion basis of the coal or iron ore disposed of as long-term capital gain or ordinary loss under section 1231. No percentage depletion allowance may be claimed with respect to such income. In order to prevent operating owners from benefiting from these provisions, related party rules limit the availability of capital gain treatment.

Royalty income received by the owner of a royalty interest in timber qualifies for long-term capital gain treatment under rules similar to those applicable to coal and iron ore royalties. In addition, an owner of timber or a contract right to cut timber may elect to treat the cutting of timber (for sale or for use in the taxpayer's trade or business) as a sale or exchange of timber eligible for long-term capital gain or ordinary loss treatment under section 1231.

Reasons for Change

The special tax treatment of income from certain interests in timber, coal and iron ore is unjustified. Royalty income from these natural resources should be subject to tax on the same basis as royalty income from other investments. In addition, if items of a resource are held for sale to customers in the ordinary course of business or for use in a trade or business, income from disposition of such items should be treated on the same basis as income from other property held for the same purposes.

Proposal

The provisions establishing special tax treatment for timber, coal and iron ore royalty income would be repealed, along with the provisions permitting elective sale or exchange treatment for owners

of timber or contract rights to cut timber. In addition, timber, coal and iron ore held for sale in the ordinary course of business or for use in a trade or business would not be eligible for long-term capital gain treatment. See Ch. 7.03.

Effective Date

Capital gain treatment for royalty income from timber, coal and iron ore and capital gain treatment for cut timber eligible for elective sale or exchange treatment would be repealed effective January 1, 1989. However, between January 1, 1986, and January 1, 1989, capital gain treatment would be phased out. For corporations, capital gains from timber, coal and iron ore would be taxed at a 30 percent rate in 1986 and the rate would increase by one percent in 1987 and 1988. For individuals, the exclusion rate on capital gains from timber, coal and iron ore would be reduced to 30 percent in 1986, 20 percent in 1987 and 10 percent in 1988.

Analysis

The Administration proposal to repeal the special treatment of timber, coal and iron ore royalty income would cause all royalty income, from whatever source, to be taxed on the same basis as ordinary income.

The Administration proposal to repeal the elective sale or exchange treatment for owners of timber tracts or of contract rights to cut timber would defer the realization of gain or loss on those assets under generally applicable realization rules for property held for sale or use in a trade or business or held for investment. The character of such gain or loss would depend upon whether the interest in timber constitutes ordinary income property or a capital asset in the hands of a particular taxpayer. To provide a reasonable transition period for the timber industry, capital gain treatment for timber would be phased out over a five-year period.